ACCESSION #: 9907260102

NON-PUBLIC?: N

LICENSEE EVENT REPORT (LER)

FACILITY NAME: Oconee Nuclear Station Unit 2 PAGE: 1 OF 10

DOCKET NUMBER: 05000270

TITLE: Reactor Trip due to Secondary System DC Grounds

EVENT DATE: 06/19/99 LER #: 1999-02-0 REPORT DATE: 07/19/99

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 066%

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:

50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:

NAME: L.E. Nicholson TELEPHONE: (864) 885-3292

Regulatory Compliance Manager

COMPONENT FAILURE DESCRIPTION:

CAUSE: N SYSTEM: SN COMPONENT: LS MANUFACTURER: M322

REPORTABLE EPIX: No

SUPPLEMENTAL REPORT EXPECTED: No

ABSTRACT:

On June 19, 1999, Oconee Unit 2 was operating in Mode 1 at 66 percent Full Power. At 1015:14 hours, the Unit 2 Reactor tripped on an anticipatory trip following a Main Turbine trip. Operators took immediate action to stabilize the unit in Mode 3. No significant problems were encountered.

The trip was due to a spurious trip signal caused by two concurrent electrical ground faults in the Moisture Separator Reheater high level switches. The root cause of one

ground was a manufacturing deficiency that allowed a wire to chafe against a sharp edge. The second ground was due to missing adhesive that allowed a Mercury switch vial to move in its retaining bracket until a conductor contacted the metal bracket. The investigation determined the adhesive may have degraded over time. Corrective actions included inspecting all similar switches, moving wires away from the sharp edge, and installing new adhesive, as necessary. The switch manufacturer is being consulted for additional possible corrective actions.

The health and safety of the public was not compromised by this event.

EVALUATION:

Background

The Reactor Protective System (RPS) [EIIS:JC] is a safety-related system which monitors parameters related to the safe operation of the plant. The RPS provides a two-of-four logic for tripping the reactor in response to unit/system conditions that require a unit trip.

The Moisture Separator Reheater (MSRH) is a shell and tube heat exchanger [EIIS:HX] that separates water from the high pressure turbine exhaust steam and reheats the steam prior to supplying it to the three Low Pressure Turbines [EIIS:TRB]. The MSRH System includes four MSRHs, designated 2A1, 2A2, 2B1, and 2B2, each consisting of a moisture separator section with two stages of reheaters. The Main Turbine is automatically tripped by a MSRH high level signal to protect the Turbine from damage due to water intrusion. A turbine trip results in a RPS trip if power level is above 38 percent Full Power (FP).

The MSRH level switches [EIIS:LS] are Magnetrol type B40 Liquid Level Switches with mercury contacts. If high water level is detected by 2 of the 3 level switches on any one MSRH, Moisture Separator High Level Trip Relay KT601 will be actuated. KT601 has a ten-second time delay to prevent spurious actuation due to momentary contacts of the level switches made due to vibration or other short term spurious signals. A contact from relay KT601 is wired into the Main Turbine master trip circuit.

The mercury switches are glass vials with two contact electrodes and a quantity of liquid mercury. The mercury vials are secured to a mounting bracket by means of metal retaining clips. Manufacturer's instructions specify that the mercury vial is to be glued to the retaining clips.

Magnetrol rated the B40 level switch for high temperature applications up to 750 degrees F. The B40 switches are also specifically designed to provide greater vibration resistance.

Oconee uses Magnetrol Level switches in the following water and steam applications: Moisture Separator Reheater, High/Low Pressure Extractions Heaters (HPEH), Feedwater [EIIS:SJ] System, and Heater Drain [EIIS:SN]

System. Only the MSRH and HPEH level switches are high temperature/vibration applications.

Description of Event

On June 19, 1999, Oconee Unit 2 was operating in Mode 1 at 66 percent FP. The previous shift had reduced power on Unit 2 and secured the 2A1 Reactor Coolant Pump (RCP) due to low oil level indications. Preparations were being made to further reduce power to allow investigation of the oil level indications and refill and/or repair of the RCP oil pot.

At 1002 hours, a Control Battery [EIIS:EI] Ground Fault alarm was received on all three Oconee Units (NOTE: the DC Ground System [EIIS:FC] is shared between Units). The operators initially believed that the alarm was associated with work in progress on Unit 1. Over the next several minutes the Ground Fault Alarm alarmed and reset numerous times. Unit 1 Operations personnel initiated an investigation of the Ground Fault alarms.

At 1015:14 hours, the Unit 2 Reactor tripped. Operators noted from alarms that the Reactor Protective System tripped as an anticipatory trip following a Main Turbine trip. They took immediate action in accordance with the Emergency operating Procedure to stabilize the unit in Mode 3. There were no emergency actuations associated with this trip. All four RPS Channels tripped. The Emergency Power Switching Logic transferred power from the normal source (the unit generator) to the startup source (switchyard) as designed. The operators verified that all control rods [EIIS:AA] fully inserted and performed immediate post-trip manual actions. Reactor Coolant System (RCS) [EIIS:AB] pressure was 2135 PSIG prior to the trip and decreased to 1856 PSIG in the initial transient before increasing back to 2055 PSIG. As anticipated, the RCS inventory shrank as it cooled from 579F (normal average RCS temperature) to approximately 555F. Pressurizer level dropped from 221 inches to 82 inches. To compensate for RCS inventory shrinkage, the High Pressure Injection (HPI)

[EIIS:CB] to RCS Normal Make-up Control Valve, 2HP-120, opened automatically to increase make-up flow. However, the Operator at the controls noted that 2HP-120 operated erratically. It appeared to stick momentarily then jump further open several times. The erratic action of 2HP-120 caused HPI injection flow to the RCP seals to fluctuate. When RCP seal injection flow dropped below the 30 GPM minimum flow setpoint, an automatic start of a second HPI pump occurred at 1015:25 hours to assure adequate seal flow.

The operator at the controls opened valve 2HP-26 (HPI TO LOOP A REACTOR INLET VALVE) to increase normal make-up to the RCS at 1016:02 hours. At 1017:02 hours, the operator closed 2HP-26. Pressurizer level was restored to approximately 120 inches within three minutes after the trip. The operator secured the second HPI pump at 1030:29 hours. Subsequently, Pressurizer level began dropping as 2HP-120 appeared to be non-responsive to an increasing demand signal in a position which allowed less make-up than the system was losing to seal leak-off and RCS letdown. At 1050 hours, 2HP-120 opened in response to a 60% demand signal. HPI make-up flow reached approximately 150 gpm. The irregular operation of 2HP-120 diverted flow from the seal injection line and the 2B HPI pump again auto-started due to low seal flow. It was shut down and returned to standby mode in auto at 1058 hours.

These auto-starts of a HPI pump were associated with the role of the HPI pumps for normal RCS make-up and were not associated with the Engineered

Safeguards [EIIS:JE] role of HPI. The erratic operation of 2HP-120 is not considered safety significant. Adequate procedural guidance exists to address failure of 2HP-120 during normal or post-trip operation. Valve 2HP-26 provides a parallel flow path and can be operated remote manually by the control room operator or automatically on an Engineered Safeguard signal.

Main Steam [EIIS:SB] Steam Generator outlet pressure was 890 PSIG prior to the trip and increased to 1103 PSIG (on the B loop) immediately after the trip. Main Steam Relief Valves opened as expected during the pressure peak. Steam pressure dropped to approximately 970 PSIG momentarily before stabilizing at 1010 PSIG. Approximately fifteen minutes after the trip the operators took action, per the procedure, to

reduce steam pressure to 980 PSIG to ensure that the Main Steam Relief valves had reseated.

Because the Unit was operating with only three RCPs prior to the trip, the feedwater level in the "B" Steam Generator was initially higher than the "All Steam Generator level. Steam generator inventory reduced from the normal operating level to 25 inches as indicated on the Start-up Level [EIIS:JB] instruments. Main feedwater pumps ran back as necessary and continued to supply feedwater. Emergency feedwater was not needed and did not actuate.

Turbine By-pass Valve 2MS-19, on the "A" Main Steam header, remained closed during the trip. This failure had little or no impact on this trip.

2MS-22, the remaining By-pass valve on the "A" Main Steam header, operated properly and controlled header pressure. One Turbine By-pass valve per header is capable of providing adequate control, even at full steam load. Investigation found that the valve positioner would not respond to an input signal. The faulty valve positioner was replaced.

The Control Rod Drive trip times were reviewed. Two Control Rod Drives trip times were not recorded on the Sequence of Events Recorder [EIIS:IQ]. A limit switch providing trip time indication for the rod at core location M13 had been disconnected due to circuit problems. The rod at core location M9 appeared to have a reed switch that stuck momentarily, but operated properly during subsequent troubleshooting. An additional rod, at core location G11, had an indicated trip time of 1.401 seconds, which required analysis. A linear trending extrapolation indicated that it would not exceed the Technical Specification limit of 1.66 seconds prior to the next refueling outage on Unit 2.

After the unit was stabilized, a Post-trip review team was assembled to analyze and determine the cause of the trip.

The First Hit Panel indicated that the Main Turbine had tripped due to high Moisture Separator Reheater (MSRH) level. However, additional post trip reviews of information provided from observed plant indications and lights on the MSRH panel found that the MSRH high level switches had not actuated. Based on these two contradictory plant status indications, the equipment

Failure Investigation Process (FIP) team focused on potential

causes for a spurious actuation of the MSRH high level turbine trip relay (KT601). KT601 has a ten-second time delay to prevent spurious actuation due to momentary contacts of the level switches due to vibration or other short-term spurious signals. The FIP team discovered that two simultaneous, yet different, electrical grounds in the DC powered MSRH 2A2 high level trip circuits had resulted in a circuit bypass of two of the three level switch contacts thereby actuating relay KT601.

At 1208 hours, the trip was reported as a 4-hour non-emergency event via the Emergency Notification System.

Following the trip, the unit remained in Mode 3 during repair and refill of the 2A1 RCP lower oil pot. The unit was returned to criticality at 0313 hours on June 23, 1999 and reached 100% power at 1100 hours on June 24, 1999.

Causal Factors

The cause of the Unit 2 trip was determined to be two simultaneous, but different, electrical ground faults in Magnetrol Level Switches used in the MSRH high level alarm and trip applications. Both grounds were associated with MSRH 2A2. Although the ground alarms occurred intermittently, the end result of the two grounds was that relay KT601 coil was energized by the DC power system for at least ten seconds, thereby initiating the Unit 2 Main Turbine trip.

The root cause of one MSRH 2A2 level switch electrical ground was manufacturing deficiency due to a rough edge at the conduit entrance inside the level switch housing. Vibration induced rubbing of a tightly pulled field wire against the metal edge resulted in the insulation fraying until the conductor was exposed. The exposed conductor contacted the grounded metal housing. This particular ground resulted in relay KT601 coil being electrically tied to ground. The other side of the relay coil was connected by design to the DC power system negative bus.

The root cause of the other MSRH 2A2 level switch electrical ground was attributed to degradation of the existing adhesive that prevents the mercury contact vial from moving in its mounting clip. Visual inspection revealed that the cement which had been applied to secure the vial was

degraded and that the vial had moved in the mounting clip until a wire connecting A switch to the positive side of the DC level circuit came in contact with the mounting clip base. This particular ground resulted in a DC positive bus tie to ground.

Field inspections of the Units 1 and 2 MSRH and HPEH level switches revealed other cases where the cement was missing from switch vials and vials that had shifted in the retaining clips. The manufacturer's instructions specify that, when replacing the switch, the mercury vial may be glued to the clips using a cement such as DuPont Duco, Goodyear Pliobond, Shellac, or equivalent. However, Duke records indicate that most, if not all, of these switches were installed as assembled units. If so, the cement would have been installed by the manufacturer. The manufacturer was unable to clearly state which cement was used. Additionally, Duke personnel noted that none of the listed cements met the overall rating of 750F specified for the switches.

A search of the maintenance history database did not reveal any work orders where replacement of a vial was clearly documented. However, the potential exists that Duke personnel may have replaced individual vials. Therefore, the FIP team could not confirm that the loss of adhesive was due to a manufacturing deficiency.

It should be noted that these grounds had to occur simultaneously in order to cause the unit trip. If either ground had occurred individually, the opportunity would have existed to identify and repair the problem. In this case, ground alarms alerted Operations to the problem, but the interval between the initial alarm and the trip was too short for troubleshooting and repair to occur.

CORRECTIVE ACTION:

Immediate:

1. The operators established stable Mode 3 conditions. Subsequent:

1. Engineering confirmed that the only applications of Magnetrol level switches rated for high temperature/vibration are on the Moisture Separator Reheaters (MSRH) and High Pressure Extraction Heaters (HPEH) of all three

units.

2. The wiring of all the Unit 1 and 2 MSRH and HPEH level switches was inspected for damage, wires replaced (as necessary), and wiring slack added (as necessary) at the conduit entrances. No problems were identified on Unit 1. Two instances of chaffed insulation were identified and corrected.

3. A small quantity of RTV 736 adhesive was applied to secure the mercury contact vials to their retaining clips in all Units 1 and 2 MSRH and HPEH level switches.

Planned:

1. During the first appropriate Unit 3 outage, inspect and adjust/repair wiring, as necessary, and secure the mercury contact vials with an appropriate adhesive in Oconee Unit 3 MSRH and HPEH level switches.

A review of the present state of the DC ground system did not reveal a condition that might be a precursor of grounds capable of initiating a turbine and/or reactor trip. The identification and correction of significant DC grounds is handled relative to the severity of the ground as outlined in Selected Licensee Commitment 16.8.5. The occurrence of another combination of grounds needed to initiate a turbine trip and/or reactor trip prior to identification and correction of the ground is unlikely prior to implementation of the above corrective action. The inspection of the Unit 3 MSRH and HPEH level switches on-line is not considered urgent and performing an inspection is a significant risk to tripping the unit.

2. Model Work Orders by which future MSRH and HPEH level switches would

be replaced will be modified to require use of an appropriate adhesive to secure the mercury contact vials to their retaining clips. This corrective action may be superseded by corrective actions resulting from item 3 below.

3. Duke Energy will provide the level switch manufacturer, Magnetrol, with the final Failure Investigation Process root cause report. Duke will request that they evaluate the problems experienced with; 1) the presence of sharp edges in high vibration resistant level switch conduit entrances, and 2) the loss of mercury contact vial adhesive. Upon receipt of the manufacturer's response, Oconee will develop further corrective actions as warranted.

4. The sluggish operation of 2HP-120 is being resolved by replacement with a newer model valve. This is currently scheduled for the next refueling outage U2EOC17. The equivalent valves on the other units are also being addressed. The Unit 1 valve, 1HP-120, was replaced during the refueling outage (U1EOC18) which has just ended. 3HP-120 is currently scheduled for replacement during the next refueling outage U3EOC18.

Planned corrective actions 1 and 2 are considered to be NRC Commitment Items. These actions are the only NRC Commitment items contained in this LER.

SAFETY ANALYSIS:

The MSRH emergency high level trip is a turbine protective trip for economic reasons: high MSRH level does not affect nuclear safety.

In this event, although the trip signal was initiated spuriously due to ground faults rather than an actual high level, the plant systems and operators responded as expected. Automatic system responses and operator actions in accordance with procedures were adequate to safely control the reactor following this trip. Post-reactor trip response, as discussed in the Event Description section of this report, was within acceptable limits as defined by the Babcock and Wilcox Owners Group Transient Assessment Program.

There were no Engineered Safeguards or Emergency Feedwater actuations required as a result of this event.

Therefore, the health and safety of the public was not affected by this event.

ADDITIONAL:

There were no releases of radioactive materials, personnel injuries, or exposures associated with this event.

A search was performed on the Operating Experience database for events that involved glass mercury vial and the chaffing of wiring inside the housing of a Magnetrol Level Switches. One event, addressed in LER 287-94-01, involved a Unit 3 trip due to degradation of mercury within a vial that had lost its vacuum seal. A residue formed which allowed the mercury to stick to the contacts, resulting in a spurious trip similar to this event. The corrective actions from that event included a Nuclear Station Modification

(NSM) to revise the logic to a two of three logic scheme, adding new level switches to support the new logic, and replacing the old switches. NSM ON-22986 installed the current model of high temperature/high vibration rated switches on Unit 2 in April 1996. Similar NSMs were performed on Unit 1 in October 1997 and on Unit 3 in March 1998. As stated in the Causal Factors section, the two of three logic, coupled with system ground alarms, would normally have allowed time to troubleshoot, identify, and repair each of the observed grounds before they could have resulted in a unit trip.

ATTACHMENT 1 TO 9907260102 PAGE 1 OF 2 ATTACHMENT 1 TO 9907260102 PAGE 1 OF 2

Duke Power.

A Duke Energy Company

W.R. McCollum, Jr.

Vice President

Duke Power

Oconee Nuclear Site 7

800 Rochester Highway

Seneca, SC 29672

(864)885-3107 OFFICE

(864)885-3564 FAX

July 19, 1999

U.S. Nuclear Regulatory Commission

Document Control Desk

Washington, D.C. 20555

Subject: Oconee Nuclear Station

Docket Nos. 50-270

Licensee Event Report 270/99-02, Revision 0

Problem Investigation Process No.: 2-099-2540

Gentlemen:

Pursuant to 10 CFR 50.73 Sections (a)(1) and (d), attached is Licensee Event Report 270/99-02, concerning a Unit 2 Reactor Trip.

This report is being submitted in accordance with 10 CFR 50.73 (a)(2)(iv).

This event is considered to be of no significance with respect to the health and safety of the public.

Very truly yours,

W. R. McCollum Jr.

Attachment

cc: Mr. Luis A. Reyes

Administrator, Region II

U.S. Nuclear Regulatory Commission

61 Forsyth Street, S. W., Suite 23T85

Atlanta, GA 30303

Mr. D. E. LaBarge

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

Washington, D.C. 20555

INPO Records Center

700 Galleria Parkway, NW

Atlanta, GA 30339-5957

Mr. M. A. Scott

NRC Resident Inspector

Oconee Nuclear Station

*** END OF DOCUMENT ***